CASE: UM 1953 Phase II
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

July 26, 2019

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/201.

Q. What is the purpose of your testimony?

A. This testimony will provide the Commission with important considerations and recommendations concerning the second phase of UM 1953. This phase addresses larger policy issues not resolved or considered in the previous phase of this proceeding, which concluded in PGE’s implementation of the first tranche of its Green Energy Affinity Rider (GEAR) program. Specifically, I will cover resource procurement and how it fits into the larger planning framework, the nine conditions guiding green tariff design resulting from UM 1690, and the calculation of credits for energy and capacity.

Q. How is your testimony organized?

A. My testimony is organized as follows:

BACKGROUND

Q. What is a renewable energy tariff?

A. Staff uses the terms Voluntary Renewable Energy Tariff (VRET) or green energy tariff to generally refer to a set of programs offered throughout the United States which allow customers to choose a resource mix that is more renewable in nature than the utility's standard offers. Although the specifics of each program vary from state to state, they generally allow the customer to purchase green energy from a source outside of the utility's portfolio. PGE's program is called the Green Energy Affinity Rider (GEAR), which allows large non-residential customers to either subscribe to a PPA offering procured in tranches by the Company, or under certain circumstances, to source a project on their own and receive a set amount of power from the project. All other cost of service (COS) customers reimburse the subscribers via energy and capacity credits that are calculated based on the value of the energy and capacity the PPA provides to the system.

Q. Has the Commission adopted policies that apply to renewable energy tariffs in Oregon?

A. Yes. In Order 15-405, the Commission adopted the following nine conditions applicable to VRET programs:

1. Renewable Portfolio Standard (RPS) definitions of resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET products.

2. VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or the developer.
3. The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.
4. The VRET program size is limited to 300 aMW for PGE and 175 aMW for PacifiCorp.
5. VRET product design should be sufficiently differentiated from existing direct access programs.
6. VRET terms and conditions (including timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must propose changes to their respective direct access programs to match those changes.
7. The regulated utility may own a VRET resource, but may not include any VRET resource in its general rate base. It may recover a return on and return of its investment in the VRET resource from the VRET customer; however, the utility must share some of the return on with other utility customers for ratepayer-funded assets used to assist the VRET offering.
8. All direct and indirect costs and risks are borne by the VRET customers, shareholders of the utility, or third-party developers and suppliers with

provisions allowing independent review and verification by the Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate based system.

9. All VRET offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

Q. How did PGE's GEAR program come into effect?

A. On April 13, 2018, the Company filed a proposal for a VRET program and the Commission subsequently docketed the contested case as UM 1953. Through Order 19-075, the Commission ultimately approved PGE's request to implement a VRET program subject to certain conditions. As part of those conditions, PGE implemented a Phase 1 with a limited scope, and parties were to take part in a second phase which investigates further concerns.

Q. How is Phase I of the program limited in scope?

A. The main limiting factor is the size of the program. The Commission capped the first phase at a total of 300 MWs: 100 MW for a PGE procured program and 200 MW for a customer supplied option (CSO). The Commission also directed parties to further investigate larger policy questions as mentioned previously.

Q. What is Staff's main concern heading into the second phase of UM 1953?

A. Staff's main concern is ensuring the program does not result in any unwarranted cost shifting between program participants and COS customers. Although the Commission decided to implement the program utilizing Staff's recommended methodology for energy and capacity valuation, the first phase has not provided any insight yet into the performance of the methodology. Although Staff believes that the theoretical framework should protect COS customers from any undue cost increases, an ultimate conclusion on the impact to power costs and resource planning cannot be made until parties have had a chance to review the program's performance with empirical evidence.

Staff does not raise this concern in order to dissuade the Commission from taking meaningful action following the conclusion of the second phase of UM 1953, but rather to note that all of Staff's recommendations, while supported, should be reviewed once the program has provided informative data points.

Q. What are the implications for Staff's concern?

A. PGE's first Company procured tranche was very successful, becoming fully subscribed in a matter of minutes. It is understandable that the Company is eager to pursue the program further in order to provide customers with another tranche to fulfil demand. PGE notes in its opening testimony that it will not implement further tranches beyond the amount requested in this docket, an additional 100 MWs each for the PGE procured and the CSO.[1] This does provide Staff with a modicum of assurance that the information learned from these two phases can be utilized to ensure fair treatment for all customers, if the Commission decides to approve PGE's request. However, 500 MW is

[1] PGE/500 Sims-Tinker/4, footnote 4.

roughly 36 percent of all non-residential load in the Company's 2020 forecast.[2] This amount is large enough that the Commission should consider its ability to implement modifications to the existing programs, should it approve PGE's request. Granted, few renewable resources to this point are able to produce full nameplate capacity for 8760 hours in a year, but even renewable resources with a 30 percent capacity factor would be roughly ten percent of the entire non-residential load. A problem with the valuation methodology or adverse impacts to PGE's least cost/least risk planning would be a major issues for COS customers. Further, Staff notes that as a result of this program, PGE's IRP action plan will almost assuredly be altered from what it otherwise would have been. As Staff will discuss later, the VRET procures resources which may or may not be the optimal solution for energy and capacity shortfalls in an IRP setting. The chances of making a material impact to the IRP plan grows as the VRET grows. So even if the valuation methodology works perfectly, the GEAR will change PGE's IRP, placing VRET customers in the position of making resource choices for COS customers. This concern is further exacerbated by the fact that the VRET resources will be procured outside of the competitive bidding guidelines. It becomes a tradeoff between giving some customers greater choice and promoting renewable energy usage in the region, at the cost of allowing the IRP process to select the least cost/least risk resource for all COS customers, and allowing the competitive bidding process to procure the resource.

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[2] UE 359 - PGE/100, Niman et al./29 Table 3.

ISSUE 1, PROGRAM DESIGN

Q. What outstanding issues remain following the conclusion of Phase I of the program?

A. Parties are largely in agreement over the general structure of the program. Namely a rider in which all participants continue to pay COS rates, pay for the PPA costs and all other program costs and are reimbursed via credits for the energy and capacity the program provides to the system. The 30 kW size threshold for participants has also not been a particularly contested issue. Lastly, the dual variant approach, a PGE provided and CSO has been relatively accepted. The issues which remain in question are:

- Net Bill Savings
- CSO Eligibility Requirements
- Utility Ownership
- Participation Cap
- Risk Adjustment

Net Bill Savings

Q. What is meant by Net Bill Savings?

A. Net bill savings, incremental credits, or negative credits are a valuation methodology for energy and capacity which would allow the subscriber to realize a net savings on its utility bill below COS rates. In Order 19-075, the Commission supported Staff's and other parties' assertions that negative credits did not result in a balanced risk profile or fair rates when the program is set up with fixed credits. The Commission did, however, note that:

> As customers and PGE explore potential PPAs we will entertain individual applications for arrangements with a floating credit, which do not guarantee net savings to a participant, but may result in net participant savings. In such a circumstance, participants and not cost of service customers would bear credit inaccuracy risk. Allowing such applications as part of the Customer Supply Option will provide the opportunity to gain experience with allocating these risks and benefits to participants, and a floating credit option could in the future be made part of the program as a whole.[3]

Q. Should net bill savings be allowed in Phase 2 of the program?

A. No. Staff continues to support the currently approved methodology as it relates to fixed versus floating credits. Staff sees the fixed credit approach as the simplest way to provide potential subscribers with the ability to increase their renewable energy consumption and make important decisions regarding the financial viability of the program. This approach has already proven to be desirable to potential applicants, as the first tranche was fully subscribed very quickly. Because of this, Staff does not recommend the inclusion of negative credits in the second tranche. As noted in the Commission order, the potentiality of a floating credit on a case-by-case basis was meant to gain experience for the applicability to the program as a whole. To this point, no CSO with a floating credit has been brought before the Commission, much less provided any insight into the functionality of the mechanism. Staff understands theoretical arguments as to why the floating credit may provide a means to allow participants to realize a net savings; however, Staff still has concerns with the impact to the competitive market. As Staff noted in Phase 1 of this proceeding, the interaction between Direct Access and the VRET is of concern,

[3] Order 19-075 at 5-6.

particularly in the instance when the VRET provides an opportunity to lower energy rates below COS levels. Therefore, Staff recommends the Commission wait until further information is available before implementing a new crediting methodology.

Customer Supply Option Eligibility Requirements

Q. What are the current eligibility requirements for the CSO?

A. In the first phase and the Company's proposal for the second phase, PGE has limited the CSO to customers with loads greater than 10 MWa. As the Company states in its opening testimony, PGE proposes this requirement in order to limit the administrative costs of the program.[4] Because the Company has to review and negotiate every contract in the CSO, some size threshold is needed to reduce the number of potential resources brought by customers. Walmart argued in the first phase of the docket that certain customers may have the means to identify a resource and leverage economies of scale that do not meet this size threshold.[5]

Q. What is Staff's recommendation for the second phase of the program?

A. Staff finds merit in allowing smaller loads an opportunity to participate in the CSO as determined on a case-by-case basis. A potential solution could be to maintain the 10 MWa participation limit, but allow customers to petition the Commission for a waiver. This would allow some flexibility for customers with unique circumstances, while still limiting the administrative burden of the program. Staff notes that although the Company supplied option has been well

[4] PGE/500 Sims-Tinker/10: 11-19.
[5] Walmart/200 Chriss/10: 8-13.

received, the CSO has yet to show large customer support. Allowing exceptions may motivate more customers to participate.

Utility Ownership

Q. Has the Company requested the ability to pursue utility ownership in this program?

A. No. PGE has stated that it will not seek utility ownership for the second tranche of the program. While there are implications and special considerations for utility ownership, Staff finds a Commission decision on this point to be unnecessary and premature in this proceeding. There are not facts in the record that would demonstrate, either way, whether such treatment is appropriate in all future circumstances. Staff reserves a recommendation until such time that PGE requests to implement a tranche owned by PGE, and after Phase I participation has provided facts and information to ensure there are no unwarranted cost shifts to cost of service customers.

Participation Cap

Q. PGE has proposed to increase the participation cap by 200 MW. Does Staff agree with this approach?

A. No, not at this time. Staff understands the Company's desire to increase the PGE procured cap given the timing of PTC credit eligibility and response from customers. Staff, however, has concerns over the request to double the PGE procured program size and the necessity of increasing the CSO at this juncture.

Q. Why is Staff concerned regarding the increase to the PGE procured variant?

A. As previously mentioned, the first phase of PGE's GEAR program has yet to provide parties with information regarding the actual performance of the program methodology Assuming a second tranche would be relatively as successful as the first tranche, there is a potential risk to COS customers given the fixed nature of the crediting mechanism proposed by the Company and supported by Staff. The Company's proposal ultimately asks the Commission to approve an increased risk borne by COS customers as parties ensure the mechanism functions properly. The Commission very recently determined that 300 MWs was an appropriate level of risk to balance participant demand while protecting COS customers. PGE has not provided any new information and program participant information and impacts is not yet available. In the absence of new information, Staff questions an expanded cap and cautions that this places the Commission in the position to weigh customer demand and tax credit benefits against further risk to COS customers.

Q. Why is Staff concerned regarding the CSO cap increase?

A. Staff sees this as increasing potential risk to COS customers, like the Company supplied option, but without the offsetting apparent customer demand to this point. As such, Staff believes that this request is less supportable given the risk for COS customers to bear. Staff believes that the Commission should wait until the current 200 MW cap is closer to being filled prior to increasing it, and make the decision with the benefit of additional facts and information on the record.

Risk Adjustment

Q. What is PGE's proposed Risk Adjustment?

A. In Phase I of this proceeding, PGE justified its Risk Adjustment on the basis of shareholder risk related to the potential mismatch between a PPA and a customer's subscription term. In its opening testimony for Phase II, PGE has expanded its rationale for its proposed Risk Adjustment, and added that the charge is intended to compensate shareholders for the risk of subscriber load uncertainty, resource variability, and PPA-related risks, in addition to program undersubscription.,

Q. What were parties concerns with the risk adjustment in Phase I?

A. Parties were generally concerned over the lack of detail and transparency afforded them by the Company over the methodology of the risk adjustment calculation. Staff ultimately supported PGE's proposed risk adjustment following a supplemental filing by the Company and on the condition that the Company was transparent in its calculation.

Q. Has PGE's testimony in Phase II clarified the appropriateness of both the application and calculation of the risk adjustment?

A. No. In fact, PGE's justification of the charge based on customer load variability risk, a variable resource risk, and a PPA risk has only served to make the charge more convoluted, and has introduced more questions and potential concerns.

Q. What are Staff's concerns with the additional risks as described by the Company?

A. Customer load variability risk and variable resource risk follow a similar logic as undersubscription risk, meaning that the supply and demand might not always match up perfectly as intended. Under a VRET program, Shareholders are intended to be responsible for any mismatch that occurs, with the idea that they will be compensated for that risk by program participants. Although Staff has no issue with compensating shareholders or potentially COS customers for appropriate risks, the PPA risk and lack of clarity on how risk adjustment is calculated, in light of the additional risks identified by PGE,are of concern to Staff.

Q. Why is the PPA risk of particular concern?

A. PGE describes the PPA risk as meaning to account for the exposure of risk shareholders experience as the result of contracting with a third party to provide contracted power. The actual cause of the risk is not explicitly stated, but Staff infers the reasoning based on the contractual provisions required to mitigate it. This adjustment, as Staff understands it, is effectively a return on investment for shareholders. PGE is concerned that the PPA might not produce as agreed upon in the contract. Not because of variability of the renewable resource, which is covered by the aforementioned variable resource risk, but because of issues with the third party. Staff first notes that PGE does not include any PPA risk adjustment for COS PPAs. Second, PGE identifies the project, presumably using least risk principles, so the level of risk is controlled by the Company. Lastly, the Company states that the inclusion of contract provisions to mitigate this risk would “encumber project participation and drive up prices.” However, PGE is also proposing to mitigate this risk by increasing the price to participate. It is unclear to Staff how PGE plans to mitigate this risk in a more cost-effective manner than the third party could do on its own. Instead, Staff sees this as a way for the Company to receive a return on a PPA project as if it were a Company owned project.

Q. What is Staff’s concern regarding the lack of information provided for the calculation of the risk adjustment?

A. Staff cannot come to any conclusion regarding the risk adjustment because the Company has not provided any information as to how it will quantify the noted risks. It is unclear if the risk adjustment will continue to be calculated in the same way, or if the newly discussed risks will be in addition to the undersubscription risk. Staff asks that the Company clarify its proposal and provide the methodology for quantification. It is further unclear whether subscriber load uncertainty and resource variability are risks that are shouldered by COS customers, rather than shareholders. Staff asks that the Company clarify if the customer load variability and variable resource risk could lead to the use of other COS resources to correct these issues. If this is the case, Staff would further recommend that PGE identify how COS customers are being fairly compensated and protected from potential cost shifts.

ISSUE 2, GUIDING CONDITIONS

Q. What are the original nine guiding conditions?

A. As stated above, the Commission adopted nine guiding conditions to determine the public interest of green tariff programs. They are:

1. Renewable Portfolio Standard (RPS) definitions of resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET products.
2. VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or the developer.
3. The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.
4. The VRET program size is limited to 300 aMW for PGE and 175 aMW for PacifiCorp.
5. VRET product design should be sufficiently differentiated from existing direct access programs.
6. VRET terms and conditions (including timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must propose changes to their respective direct access programs to match those changes.

7. The regulated utility may own a VRET resource, but may not include any VRET resource in its general rate base. It may recover a return on and return of its investment in the VRET resource from the VRET customer; however, the utility must share some of the return on with other utility customers for ratepayer-funded assets used to assist the VRET offering.
8. All direct and indirect costs and risks are borne by the VRET customers, shareholders of the utility, or third-party developers and suppliers with provisions allowing independent review and verification by the Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate based system.
9. All VRET offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

Q. What is PGE proposing as the new guiding conditions for VRET programs?

A. PGE has proposed seven conditions to replace the nine adopted in 2016. They are:

1. Renewable Portfolio Standard (RPS) definitions of resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET products.
2. Voluntary renewable energy options only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants.

3. The generation resources supporting the program must be new or expanded, incremental renewable resources; the year that a voluntary renewable energy program eligible resource became operational should be no earlier than one year prior to program enrollment.
4. The voluntary renewable energy program size is limited to 500 MW for PGE.
5. The regulated utility may own a voluntary renewable energy resource, and when it does, it must continue to ensure there is no cost shifting to non-participants.
6. All direct and indirect costs and risks are borne by the participating voluntary renewable energy customers, shareholders of the utility or third party developers and suppliers with provisions allowing independent review and verification by Commission Staff of all utility cost.
7. All voluntary renewable offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, reasonable, and offered to eligible customers on a nondiscriminatory basis.[6]

In sum, PGE has proposed to modify conditions 2, 3, 4, 7, 8 and 9. The Company has also proposed to remove conditions 5 and 6, and to leave condition 1 unchanged.

Q. What is Staff's recommendation regarding the Company's proposal to leave condition 1 unchanged?

[6] PGE/500, Sims-Tinker/25-26.

A. Staff supports the Company's proposal to leave condition one unchanged. Staff does not believe that any new circumstances warrant a change to the condition.

Q. What is Staff's recommendation regarding the Company's proposal to modify condition 2?

A. Staff supports the Company's proposal to modify the second condition. This follows from the Commission's direction in Order 19-075, whereby the Company is not allowed to accept participants to donate RECs for RPS compliance. This results in a condition that better complies with the intent of the RPS and additionality goals for the VRET.

Q. What is Staff's recommendation regarding the Company's proposal to modify condition 3?

A. Staff supports the Company's proposed modifications to the third condition. A guideline to encourage additionality for renewable generation should not be fixed on a particular date, but instead change with time. Staff notes that this condition does not clarify if the project must be built for the VRET. Staff prefers to leave room for interpretation as Staff does not currently believe there is a need for the project to be built for the PGE's GEAR program itself in order to achieve additionality. If the project is built for other purposes, but later finds it can serve the program, then presumably another project could be built for the original purpose and the program would have achieved additional renewable energy production.

Q. What is Staff's recommendation regarding the Company's proposal to modify condition 4?

A. Staff supports the Company's proposal to modify the condition 4 to match the currently approved program cap. As discussed previously in this testimony, Staff does not agree that the cap should be 500 MW at this time.

Q. What is Staff's recommendation regarding the Company's proposal to delete condition 5?

A. Staff does not support the Company's deletion of condition 5. If the Company believes that its program is sufficiently differentiated from Direct Access, then it is complying with the guideline. However, the Commission retains the obligation to remove barriers to the competitive market place. This condition ensures the protection of competitive wholesale markets. PGE's testimony in this proceeding does not substantively address these concerns.

Q. What is Staff's recommendation regarding the Company's proposal to delete condition 6?

A. Staff supports modification of condition 6, rather than deletion. Staff does not believe, in light of the approved program, that all terms and conditions must necessarily directly match Direct Access, particularly as terms and conditions may vary depending on the Direct Access program. The programs are differentiated enough that simple one to one conversions cannot be made. For example, not all Direct Access programs have the same transition costs. This is not to say, however, that Staff believes no consideration should be made between the offerings of VRET and Direct Access. Therefore, Staff recommends an alternative to condition 6.

Voluntary renewable energy product offering terms and conditions must fairly account for differences from Direct Access programs. The Utility may propose terms and conditions that differ from current Direct Access provisions, but must provide evidentiary support for those differences and must consider changes to their direct access programs to match VRET terms and conditions, as appropriate.

This allows for differences, but ensures that fair treatment for DA customers is given.

Q. What is Staff's recommendation regarding the Company's proposal to modify condition 7?

A. Staff supports the Company's proposal to modify condition 7. Staff notes that this does not equate to a recommendation to allow the Company to pursue utility ownership without further Commission decision. Staff notes that the previous condition allowed for Utility ownership, but Staff views the Company's modification as providing a more general 'no cost shifting' rule which better applies to all potential utility owned proposals.

Q. What is Staff's recommendation regarding the Company's proposal to modify condition 8?

A. Staff does not support the Company's proposal to modify condition 8. According to PGE's testimony, it is already complying with the existing guideline in its proposed GEAR program. However, future program offerings or other VRET proposals from other utilities may be structured differently, and may not require continued service on a COS schedule. Staff finds that providing a non-exhaustive, illustrative list of types of costs is appropriate. PGE has not provided any testimony in support of this modification.

Q. What is Staff's recommendation regarding the Company's proposal to leave condition 9 unchanged?

A. Staff supports the Company's proposal to leave condition one unchanged. Staff does not believe that any new circumstances warrant a change to the condition.

Q. Does Staff have any other additions or changes it recommends making?

A. Not at this time, though Staff may modify its recommendations based on the testimony provided by other parties.

ISSUE 3, RESOURCE PROCUREMENT AND PLANNING

Competitive Bidding Rules (CBR)

Q. What is PGE's proposal for application of the CBR?

A. PGE requests the Commission waive the rules for the VRET program.

Q. What is Staff's recommendation for the Company's proposal?

A. Staff recommends that a waiver under the approved cap be granted, but not waived completely for the GEAR. PGE raises some persuasive arguments concerning flexibility and cost. However, the CBR are meant to ensure a fair outcome for customers and a fair process for potential suppliers. While Company incentives for program participation should result in fair outcomes and least cost/risk procurement, Staff is uncomfortable with a blanket waiver. The larger the VRET program becomes, the bigger the concern is that resources are procured in a competitive, fair process, particularly if PGE seeks to own VRET resources in the future. Additionally, Staff and the Commission cannot guarantee a fair process for potential suppliers over time if PGE's procurements over time tend to favor particular developers who have an established relationship with PGE. In order to limit this potential risk, Staff recommends the Commission limit the waiver such that a review of the processes to date can be done prior to further procurements.

Incremental Resources

Q. Please summarize PGE's proposal regarding resources eligible to participate in the GEAR program.

A. PGE proposes to require all projects be new or expansions and built for the GEAR in order to qualify for the program as part of the PGE procured portion. For the CSO option, PGE is willing to evaluate any renewable resource that the subscriber brings forward.

Q. Does Staff agree with PGE's recommendation regarding a project built specifically for the GEAR program requirement?

A. No. As previously mentioned, Staff believes that the program can achieve additionality without the requirement that the project be built specifically for the program. Further, this raises several questions and concerns about how that determination is made, and what process would ensue if there is a dispute about PGE's conclusion as to whether the project is built for the GEAR program. Staff also disagrees that PGE should consider any renewable resource as part of the CSO. One of the goals of the VRET is to promote additionality. If the program is left open to any resource that goal will not be achieved. Staff prefers consistent requirements between the two programs.

<u>Transmission Requirements</u>

Q. Please summarize PGE's proposal regarding transmission requirements.

A. PGE is requesting that the firm transition requirement be maintained in the second phase. They further commit to ensuring "that our procurement processes are as consistent as possible should the RFP requirements change." The Company also includes a discussion of the process by which the transmission requirements should be examined and it can be presumed that they are willing to be involved in that process.

Q. Does Staff agree with PGE's proposal regarding transmission requirements?

A. Yes. Staff supports the Company's proposal to address the transmission requirements more holistically in a separate forum. In this docket, Staff views the fair treatment between developers, the PGE procured and CSO variants, and the VRET and the numerous other programs and processes that require transmission rights as achieving a fair and reasonable outcome. Staff has concerns with applying a different standard between the VRET and standard RFP procurement as the latter is the process by which we achieve least cost/risk planning. Should the VRET not maintain similar requirements, COS customers may be put further at risk and receive an outcome more differentiated that the least cost/least risk plan. PGE's proposal achieves a fair outcome for those involved in the VRET and ensures that any potential improvements to transmission related issues will be dutifully applied. Staff finds the Company's recommendation reasonable and fair.

<u>Interactions with Integrated Resource Planning</u>

Q. How has the Company proposed to integrate the VRET into the IRP process?

A. PGE notes that the resources involved in the GEAR will be included in IRP planning. Further, because the credit methodology is based on IRP valuations, the cost to COS customers will be based on the value as defined in the IRP process. The greater and more costly the need, the higher the credit will be, which results in a benefit calculation based on portfolio need.

Q. Does Staff support PGE's mitigation techniques to the impacts of adding significant new GEAR resources?

A. Yes. Staff believes that the Company's proposal to include sensitivity analysis around future GEAR participation within the IRP is the best way to avoid potential mismatches between actual value and IRP forecasted benefit. Being cognizant of the potential increases to the resource portfolio outside of the IRP should result in an IRP process which achieves the best outcome for COS customers. Staff does note, however, that in spite of the best efforts by PGE, the fact is that the resource portfolio mix will be changed because of the GEAR.

Q. Why does Staff see it as a foregone conclusion that the GEAR will impact the IRP action plan?

A. An IRP utilizes a number of different solutions beyond a simple renewable resource in order to evaluate the best way to serve the needs of customers. As the GEAR grows, the more likely it will be that an IRP process without a GEAR program would have found a DSM, storage, or even Company built resource to meet the need at a lower cost than actual resource procurements. As such, regardless of the safeguards put in place, the GEAR will change the IRP action plan and potentially costs for COS customers. The crediting methodology should account for some of this as the credits are based on IRP valuation; however, there are two potential concerns. The first is that the crediting methodology is flawed in some sense. The IRP ultimately estimates what resource costs will be, where as an RFP better indicates market prices for those resources. The second is that an IRP occurs every two years, whereas the VRET resources are 20 year commitments. As the prices for a particular technology change, the IRP will adapt to them, but a VRET based resource will remain fixed. If in five years, battery technology becomes markedly cheaper, the IRP action plan would more likely include storage as an optimal solution. The VRET only procures particular resources, meaning that the resulting portfolio mix, transmission needs, and balancing needs will be skewed from the IRP plan without the VRET program. Staff encourages the Commission to continue to monitor the impacts the GEAR has on the resulting portfolio mix. The simplest way to examine this impact would be to run a “with and without GEAR” scenario in the IRP. This can be used to ensure that COS customers are not the subject of unwarranted cost shifting or other impacts due to the increased reliance on a particular resource (wind or solar PPAs) to meet energy and capacity needs.

Q. Does this conclude your testimony?

A. Yes.